Appendix D: Fluid Minerals

Procedures in Oil and Gas Recovery and Operations and Summary of the Billings Reasonably Foreseeable Development Scenario

This page left intentionally blank

Table of Contents

This page intentionally left blank.

D. Fluid Minerals: Procedures in Oil and Gas Recovery and Operations and Summary of the Billings Reasonably Foreseeable Development Scenario

D.1 Geophysical Operations

Oil and gas reservoirs are discovered by either direct or indirect exploration methods. Direct methods include mapping of surface geology, observing oil or gas seeps, and gathering information on hydrocarbon shows observed in drilling wells. Indirect methods include various types of geophysical exploration such as seismic, gravity, and magnetic surveys, which use remote data gathering techniques to delineate subsurface structures or lithologic changes that are not directly observable, but that may contain or trap oil and gas. Data is often acquired using equipment mounted on surface vehicles or aircraft. Information from geophysical exploration can lead oil companies or others to request that lands be offered for lease, or assist in the selection of drill sites on existing leases. However, a federal oil and gas lease is not required in order to conduct geophysical operations. Existing road systems are used where available. Roads may be cleared of vegetation and loose rocks to improve access for trucks if the permit allows that action.

Blading and road construction for seismic operations are not usually allowed so that environmental impacts are minimized. In areas with rugged terrain or without access roads, and during certain seasons of the year, seismic work is conducted by helicopter rather than by ground vehicles. Other geophysical operations that do not cause additional surface disturbance include remote sensing, and gravity, and aeromagnetic surveying.

D.1.1 Geophysical Permitting Procedures and Regulations

Geophysical operations on and off an oil and gas lease are reviewed by the Federal Surface Management Agency (SMA), which can include the BLM, Bureau of Reclamation, or U.S. Forest Service (USFS). Close cooperation between the operator and the managing agency during geophysical operations minimizes surface impacts and protects other resources.

D.1.1.1 Notification Process

Geophysical operations on public lands are reviewed by the BLM. Geophysical exploration on public lands requires review and approval following the procedures in 43 CFR Subparts 3150, 3151, and 3154. In the Billings Field Office, the Field Manager is authorized to approve geophysical operations. The responsibilities of the geophysical operator and the Field Manager during geophysical operations are described below.

D.1.1.2 Geophysical Operator

The operator is required to file a Notice of Intent to Conduct Oil and Gas Exploration Operations (form 3150-4) for operations on public lands administered by the BLM. Maps (preferably

1:24,000 scale topographic maps) showing the location of the proposed lines, access routes and ancillary facilities must accompany the Notice of Intent. When the Notice of Intent is filed, the authorized officer may request a prework conference or field inspection. Special requirements or procedures that are identified by the authorized officer are included in the Terms and Conditions for Notice of Intent to Conduct Geophysical Exploration (form 3150-4 and a copy of the state requirements). Any changes in the original Notice of Intent must be submitted in writing to the authorized officer. Written approval must be secured before activities proceed.

Bonding of the operator is required. A copy of proof of satisfactory bonding shall accompany the Notice of Intent. Proper bonding may include a $5,000 individual, $25,000 statewide, or $50,000 nationwide geophysical exploration bond. In lieu of an exploration bond, a statewide or nationwide oil and gas bond may be used if it contains a rider for geophysical exploration. The operator is required to comply with applicable federal, state, and local laws such as Federal Land Policy and Management Act of 1976, the National Historic Preservation Act of 1966, and the Endangered Species Act of 1973, as amended. Earth-moving equipment shall not be used without prior approval. Operators may be required to submit an archeological evaluation and the agency provide NEPA documentation for cultural and wildlife resources if dirt work or other surface disturbance is contemplated, or if there is reason to believe that these resources may be adversely affected. When geophysical operations have been completed including any required reclamation or rehabilitation, the operator is required to file a Notice of Completion (form 3150-5) including certification that all terms and conditions of the approved Notice of Intent have been fulfilled. The operator must also submit a map that shows the actual line location, access route, and other survey details.

D.1.1.3 BLM Field Manager (authorized officer)

The authorized officer is required to contact the operator within five working days after receiving the Notice of Intent to explain the terms of the notice, including the "Terms and Conditions for Notice of Intent to Conduct Geophysical Exploration," current laws, and BLM administrative requirements. At the time of the prework conference or field inspection, written instructions or orders are given to the operator. The authorized officer is responsible for the examination of resource values to determine appropriate surface protection and reclamation measures. Compliance inspections during the operation ensure that stipulations are followed. The authorized officer is required to make a final inspection following filing of the Notice of Completion Compliance inspections upon completion of work ensure that required reclamation is properly completed. When reclamation is approved, obligation against the operator's bond is released. The BLM has 30 days after receipt of the Notice of Completion to notify the operator whether the reclamation is satisfactory or if additional reclamation work is needed. Bonding liability will automatically terminate within 90 days after receipt of the Notice of Completion unless the authorized officer notifies the operator of the need for additional reclamation work.

D.1.1.4 State Standards

Geophysical operators register with the state through the County Clerk and Recorder's office. State regulations include requirements for permitting geophysical activities such as shothole locations, drilling techniques, plugging techniques, bonding, and reclamation.

D.1.1.5 Mitigation

When a geophysical Notice of Intent is received, restrictions may be placed on the application to protect resource values or to mitigate impacts. Many of these requirements may be the same as the oil and gas lease stipulations adopted in the RMP. Other less restrictive measures may be used when impacts to resource values will be less severe. This is due in part to the temporary nature of geophysical exploration. Seasonal restrictions may be imposed to reduce conflicts with wildlife, watershed damage, and hunting activity. The decisions concerning the level of protection required are made on a case-by-case basis when a Notice of Intent is received.

D.2 Leasing Process

Federal oil and gas leasing authority is found in the 1920 Mineral Leasing Act, as amended, for public lands and the 1947 Acquired Lands Leasing Act, as amended, for acquired lands. Leasing of federal oil and gas is affected by other acts such as National Environmental Policy Act of 1969, the Wilderness Act of 1964, National Historic Preservation Act of 1966, the Endangered Species Act of 1973, Federal Land Policy and Management Act of 1976, and the Federal Onshore Oil and Gas Leasing Reform Act of 1987. Regulations governing federal oil and gas leasing are contained in 43 CFR Part 3100 with additional requirements and clarification found in Onshore Operating Orders and Washington office manuals, handbooks and instruction memorandums.

The 1920 Mineral Leasing Act provides that all public lands are open to oil and gas leasing unless a specific order has been issued to close an area. Leasing procedures for oil, conventional gas, and coal bed natural gas are the same.

The lease grants the right to explore, extract, remove, and dispose of oil and gas deposits that may be found in the leased lands. The lessee may exercise the rights conveyed by the lease subject to the lease terms and attached stipulations, if any.

Lease rights may be subject to lease stipulations and permit approval requirements. Stipulations and permit requirements describe how standard lease rights are modified. Lease constraints or requirements may also be applied to applications for permit to drill on existing leases provided the constraints or requirements are within the authority reserved by the terms and conditions of the lease. The stipulations and conditions of approval must be in accordance with laws, regulations, and lease terms. The lease stipulations and permit conditions of approval allow for management of federal oil and gas resources in concert with other resources and land uses. The BLM planning process is the mechanism used to evaluate and determine where and how federal oil and gas resources will be made available for leasing. In areas where oil and gas development may conflict with other resources, the areas may be closed to leasing. Areas where oil and gas development could coexist with other land uses or resources will be open to leasing. Leases in these areas will be issued with standard lease terms or with added stipulations based upon decisions in the land use document. Added stipulations are a part of the lease only when environmental and planning records demonstrate the necessity for the stipulations (modifications of the lease).

Currently, leases are issued as either competitive leases or noncompetitive leases with 10-year terms. Competitive leases will be sold to the highest qualified bidder at oral auctions that are held at least quarterly. Tracts that receive no bid at the sale are available for the filing of noncompetitive offers for two years following the sale. All offers filed the day after the sale (referred to as day-after-the-sale filings) are considered simultaneously filed. This means that if there is more than one offer filed for a specific parcel the day after the sale, a drawing must be held to determine the priority on multiple offers. Noncompetitive offers filed after that time are on a first-come first-served basis. If there are no offers filed for a parcel for the two-year period after the sale, the lands must be nominated again for competitive leasing. Rental payments for these leases will be $1.50 per acre for the first 5 years and $2.00 per acre. If the lessee establishes hydrocarbon production, the leases can be held for as long as oil or gas is produced in paying quantities. The royalty rate for leases issued following the 1987 Oil and Gas Leasing Reform Act is 12½ percent, of which one-half of the royalty collected is disbursed to the State of Montana for collections from public domain lands (acquired lands have various disbursements). Minimum royalty is the same amount as the rental. Future interest leases are available for entire or fractional mineral estates that have not reverted to federal ownership. These are minerals that are reserved by the grantor for a specific period of time in warranty deeds to the United States. Any future interest leases may be obtained only through the competitive bidding process and are made effective the date of vesting of the minerals with the United States.

D.2.1 Resource Management Plan Maintenance

New information may lead to changes in existing resource inventories. New use areas and resource locations may be identified or use areas and resource locations that are no longer valid may be identified. These resources usually cover small areas requiring the same protection or mitigation as identified in this plan. Identification of new areas or removal of old areas that no longer have those resource values will result in the use of the same lease stipulation identified in this plan. These areas will be added to the existing data inventory without a plan amendment. In cases where the changes constitute a change in resource allocation outside the scope of this plan, a plan amendment would be required.

D.2.2 Lease Stipulations

Certain resources in the planning area require protection from impacts associated with oil and gas activities. The specific resource and the method of protection are contained in lease stipulations. Lease stipulations are usually no surface occupancy, controlled surface use, or timing limitation. A notice may also be included with a lease to provide guidance regarding resources or land uses. While the actual wording of the stipulations may be adjusted at the time of leasing, the protection standards described will be maintained.

D.2.3 Controlled Surface Use

Use or occupancy is allowed (unless restricted by another stipulation), but identified resource values require special operational constraints that may modify the lease rights. Controlled surface use is used for operating guidance, not as a substitute for the no surface occupancy or timing stipulations.

D.2.4 No Surface Occupancy (NSO)

Use or occupancy of the land surface for fluid mineral exploration or development is prohibited in order to protect identified resource values. The no surface occupancy stipulation includes stipulations which may have been worded as “No Surface Use and Occupancy,” “No Surface Disturbance,” “Conditional No Surface Occupancy,” and “Surface Disturbance or Occupancy Restriction (by location).”

D.2.5 Timing Limitation (Seasonal Restriction)

Prohibits surface use during specified times to protect identified resource values. This stipulation does not apply to the operation and maintenance of production facilities unless the findings of analysis demonstrate the continued need for such mitigation and that less stringent, project-specific mitigation measures would be insufficient.

D.2.6 Waivers, Exceptions, Modifications

Lessees must honor lease stipulations when an Application for Permit to Drill or other surface disturbing operations are proposed to explore and develop a lease, unless the BLM grants a waiver, exception, or modification to a lease stipulation. This RMP establishes the guidelines by which future waivers, exceptions, or modifications are granted within the Billings Field Office. Substantial modification or waiver is subsequent to lease issuance is subject to public review for at least a 30-day period.

> **Exception:** A case-by case exemption from a lease stipulation. The stipulation continues to apply to all other sites within the leasehold to which the restrictive criteria apply.
>
> **Modification:** Fundamental changes to the provisions of a lease stipulation, either temporarily or for the term of the lease. Therefore, a modification may include an exemption from or alteration to a stipulated requirement. Depending on the specific modification, the stipulation may or may not apply to all other sites within the leasehold to which the restrictive criteria apply.
>
> **Waiver:** Permanent exemption from a lease stipulation. The stipulation no longer applies anywhere within the leasehold.

D.3 Permitting

A federal lessee or operator is governed by procedures set forth in the Code of Federal Regulations at 43 CFR Part 3160, Onshore Oil and Gas Order No. 1, “Approval of Operations on Onshore Federal and Indian Oil and Gas Leases, ” issued under 43 Code of Federal Regulations (CFR) 3164 and other orders and notices.

The lessee may conduct lease operations after lease issuance. However, proposed drilling and associated activities must be approved in advance before beginning operations. Therefore, before beginning construction or the drilling of a well, the lessee or operator must file an Application for Permit to Drill (APD) with the BLM Miles City DO. A copy of the application will be posted in the DO and Billings Field Office (FO), and if applicable, in the office of the Surface Management Agency (SMA) for a minimum of 30 days for review by the public. After 30 days, the application can be approved in accordance with (a) lease stipulations, (b) Onshore Oil and Gas Orders, and (c) Onshore Oil and Gas regulations (43 CFR Part 3160) if it is administratively and technically complete.

Evidence of bond coverage for lease operations must be submitted with the application. Bond amount must not be less than a $10,000.00 lease bond, a $25,000.00 statewide bond or a $150,000.00 nationwide bond.

Pre-drill on-site inspections will be conducted for all wells. The inspection makes possible selection of the most feasible well site and access road from environmental, geological, and engineering points of view. The purpose of the field inspection is to evaluate the operator's plan, assess the situation for possible impacts, and to formulate resource protection stipulations. Surface use and reclamation requirements are developed during the on-site inspection that is usually conducted within 15 days after receipt of the Notice of Staking (NOS) or APD. For operations proposed on privately-owned surface, if the operator after a good-faith effort is unable to reach an agreement with the private surface owner, the operator must post a bond to cover loss of crops and damages to tangible improvements prior to approval of the APD.

Normally, site-specific mitigations in the form of conditions of approval are added to the APD for protection of surface and subsurface (including groundwater) resource values in the vicinity of the proposed activity. The BLM is responsible for preparing environmental documentation necessary to satisfy the National Environmental Policy Act (NEPA) requirements and provide any mitigation measures needed to protect the affected resource values.

Conditions of approval implement the lease stipulations and are part of the permit when environmental and field reviews demonstrate the necessity for operating constraints or requirements. A surface restoration plan is part of an approved permit, either an APD or Sundry Notice that includes other surface-disturbing activities. The authorized officer will act on the application in one of two ways:

Within 30 days after the operator has submitted a complete application including incorporating any changes that resulted from the onsite inspection the BLM will:

1. Approve the application subject to reasonable conditions of approval if the requirements of the National Environmental Policy Act (NEPA), National Historic Preservation Act (NHPA), Endangered Species Act (ESA), or other applicable law have been completed and, if on FS lands, FS has approved the Surface Use Plan of Operations; or

2. Notify the operator that it is deferring action on the permit. The notice of deferral must specify:

    a. Any action the operator could take that would enable BLM to issue a final decision on the application, with FS concurrence if appropriate. Actions may include but are not limited to; assistance with data gathering or assistance with preparation of analyses and documents;

b. And if necessary, a list of actions that BLM or the FS, if appropriate, need to take, including completing requirements of NEPA or other applicable law and a schedule for completing these actions.

The operator has 2 years from the date of the notice of deferral to take the action specified in the notice. If all analyses required by NEPA, NHPA, ESA and other applicable laws have been prepared, BLM and with FS concurrence, if appropriate, shall make a decision on the permit within 10 days of receiving a report from the operator addressing all of the issues or actions specified in the deferral notice and certifying that all required actions have been taken. If the operator has not completed the actions specified in the notice, BLM may deny the permit at any time later than 2 years from the operator's receipt of the deferral notice."

For drilling operations on lands with state or private mineral ownership, the lessee must meet the requirements of the mineral owner and the state regulatory agency. The BLM does not have jurisdiction over nonfederal minerals; however, the BLM has surface management responsibility in situations of BLM surface over nonfederal mineral ownership.

When final approval is given by the BLM, the operator may begin construction and drilling operations Approval of an APD is valid for one year. If construction does not begin within one year, the permit must be reviewed prior to approving another APD.

A Sundry Notice is used to approve other surface and subsurface lease operations. When a well is no longer useful, the well is plugged and the surface reclaimed. A Sundry Notice is also used to approve well plugging and reclamation operations, although verbal approval for plugging may be given for a well that was drilled but not completed for production.

The period of bond liability is terminated after all wells covered by the bond are properly plugged and the surface reclaimed. The lands may then become available for future leasing.

D.4 Application for Permit to Drill

Applications for Permit to Drill are approved for the Billings Field Office by the supervisor of the Miles City DO. The approved APD includes Conditions of Approval, and Informational Notices that cite the regulatory requirements from the Code of Federal Regulations, Onshore Operating Orders and other guidance.

D.5 Conditions of Approval

Conditions of approval are mitigation measures that implement restrictions in light of site-specific conditions. General guidance for conditions of approval and surface operating standards is found in the BLM and USFS brochure entitled "Surface Operating Standards for Oil and Gas Exploration and Development" (USDI, BLM1989c) and BLM Manual 9113 entitled "Roads".

The BLM commonly applies best management practices when approving APDs. The sources of many of these may be found in RMP Appendix B.

The following mitigation measures may be applied to approved permits to drill as conditions of approval. The listing is not all-inclusive, but presents some possible conditions of approval that may be used in the planning area. The wording of the condition of approval may be modified or additional conditions of approval may be developed to address specific conditions.

In addition to the best management practices identified in Appendix B, the BLM will also develop site-specific practices on a case-by-case basis as needed.

D.6 Construction

Construction of the access road and the well site is necessary before drilling operations begin. The extent of surface disturbance necessary for construction depends on the terrain, depth of the well, drill rig size, circulating system, and safety standards.

The depth of the drill test determines the size of drill rig needed, and therefore, the size of the work area necessary, the need for all-weather roads, water requirements, and other needs. The terrain influences the construction problems and the amount of surface area to be disturbed. Reserve pit size may vary because of well depth, drill rig size, or circulating system.

Access roads to well sites in the planning area usually consist of running surfaces 14 to 24 feet wide that are ditched on one or both sides. Many of the roads constructed will follow existing roads or trails. New roads might be necessary because existing roads are not at an acceptable standard. For example, a road may be too steep so that realignment is necessary.

Roads can be permanent or temporary, depending on the success of the well. The initial construction can be for a temporary road; however, it is designed so that it can become permanent if the well produces. Not all temporary roads constructed are immediately rehabilitated when the drilling stops. A temporary road is often used as access to other drill sites. The main roads and temporary roads require graveling to be maintained as all-weather roads. This is especially important in the spring. Access roads may be required to cross public lands to a well site located on private or state lands. The portion of the access road on public land would require a BLM right-of-way.

The amount of level surface required for safely assembling and operating a drilling rig varies with the type of rig, but averages 300 feet by 400 feet. Approximately 3-1/2 acres would be impacted by well site construction. The area is cleared of large vegetation, boulders, or debris. Then the topsoil is removed and saved for reclamation. A level area is then constructed for the well site, which includes the reserve pit. Bulldozers and motor scrapers are typically used to construct the well pad. The well pad is flat (to accommodate the drill rig and support equipment) and large enough to store all the equipment and supplies without restricting safe work areas. The drill rig must be placed on “cut” material rather than on “fill” material to provide a stable foundation for the rig. The degree of cutting and filling depends on terrain; that is, the flatter the site, the less dirt work is required.

Hillside locations are common, and the amount of dirt work varies with the steepness. A typical well pad will require a cut 10 feet deep against the hill and a fill 8 feet high on the outside. It is normal to have more cut than fill to allow for compaction, and any excess material is then stockpiled. Eventually, when the well is plugged and abandoned, excavated material is put back in its original place.

Reserve pits are normally constructed on the well pad. Usually the reserve pit is excavated in "cut" material on the well pad. The reserve pit is designed to hold water, drill cuttings, and used drilling fluids. Generally, reserve pits are rectangular in shape and 8 to 12 feet deep, however, the size and number of pits depends on the depth of the well, circulating system and anticipated down hole problems, such as excess water flows. The reserve pit can be lined with a synthetic liner to contain pit contents and reduce pit seepage. Not all reserve pits are lined; however, BLM can require a synthetic liner stipulations and conditions attached to the approved APD and the drilling equipment is moved to another location.

If the well is a producer, casing is set and cemented in place.

Directional drilling may be used where the drill site cannot be located directly over the drilling target. There are limits to both the degree that the well bore can be deviated from the vertical and the horizontal distance the well can be drilled away from the well site.

Horizontal wells are drilled similarly to directional wells, except that the bottomhole location of the well is not a single point, but rather a lateral horizontal section. They are drilled to increase the recovery oil and gas reserves from vertically fractured reservoirs, or reservoirs with directional permeability.

D.7 Environment and Safety

During drilling and production operations for any well, the BLM will enforce the provisions of the regulations, Onshore Oil and Gas Operating Orders, and Notice to Lessees NTL-MSO-1-92, Report of Undesirable Events, to ensure operations are carried in a manner that protects the mineral resources, other natural resources, and environmental quality. Regulations at 43 CFR § 3162.5 require that the operator exercise due care and diligence to assure that leasehold operations do not result in undue damage to surface or subsurface resources or surface improvements. All produced water must be disposed of by methods approved by the BLM. Upon completion of operations the operator shall reclaim the surface in a manner approved of by the BLM. All spills or leakages of oil, gas, produced water, toxic liquids, blowouts, fires, personal injuries, and fatalities must be reported by the operator. The operator is required to exercise care in taking measures approved by the BLM to control and remove pollutants and extinguish fires. An operator's compliance with the regulations at 43 CFR § 3162.5 does not relieve him of the obligation to comply with any other law or regulations. Finally, the regulations authorize the BLM to require an operator to file a contingency plan describing procedures to be implemented to protect life, property, and the environment.

D.8 Informational Notice

The following items are from the federal oil and gas regulations (43 CFR 3160, Onshore Orders Numbers 1 and 2, NTLs, and other guidance). This is not a complete list of requirements but an abstract of some major requirements.

1. ***General Requirements***

   a. The lessee or designated operator shall comply with applicable laws and regulations; the lease terms, onshore oil and gas orders, NTLs; and other orders and instructions of the AO. Any deviation from the terms of the approved APD requires prior approval from the BLM (43 CFR 3162.1(a))

   b. If at any time the facilities located on public lands authorized by the terms of the lease are no longer included in the lease (caused by a contraction in the unit or other lease or unit boundary change), the BLM will process a change in authorization to the appropriate statute. The authorization will be subject to appropriate rental or other financial obligations determined by the AO.

2. ***Drilling Operations (Onshore Order No. 2)***

   a. Onshore Order No. 2 requires surface casing shall have centralizers on the bottom three joints of the casing (a minimum of one centralizer per joint, starting with the shoe joint) (BLM 1988).

   b. If drill stem tests are run, the MCFO shall be notified at least 6 hours prior to testing. All applicable safety precautions outlined in Onshore Order No. 2 shall be observed (BLM 1988).

   c. All indications of usable water (10,000 parts per million or less total dissolved solids) shall be reported to the MCFO prior to running the next string of casing or before plugging orders are requested, whichever occurs first.

3. ***Well Abandonment (43 CFR 3162.3-4, Onshore Order No. 1, Sec. V)***

   a. Approval for abandonment shall be obtained prior to beginning plugging operations. Initial approval for plugging operations may be verbal, but shall be followed up in writing within 30 days. Subsequent and final abandonment notifications are required and shall be submitted on SNs and Reports on Wells, Form 3160.5, in triplicate.

4. ***Reports and Notifications (43 CFR 3162.4-1, 3162.4-3)***

   a. Within 30 days of completion of the well as a dry hole or producer, a copy of all logs, core descriptions, core analyses, well-test data, geologic summaries, sample descriptions, or data obtained and compiled during the drilling, workover, or completion operations shall be filed with Well Completion or Recompletion Report and Log, Form 3160-4, in duplicate.

b. In accordance with 43 CFR 3162.4-3, this well shall be reported on MMS Form 4054, "Oil and Gas Operations Report, starting with the month in which any operations commence, including drilling, and continuing each month until the well is physically plugged and abandoned.

c. Notify this office within 5 business days of production start-up if either of the below conditions occur:

   i. the well is placed on production ("placed on production" means shipment or sales of hydrocarbons from temporary tanks, production into permanent facilities, or measurement through permanent facilities); or

   ii. the well resumes production after being off production for more than 90 days.

Notification may be written or verbal with written follow-up within 15 days and must include the following information:

a. operator name, address, and telephone number;

b. well name and number, county and state;

c. well location, "1/4-1/4, Section, Township, Range, P.M.";

d. date well begins or resumes production;

e. the nature of the well's production (crude oil, or crude oil casing gas, or natural gas and entrained liquid hydrocarbons);

f. the federal or Indian lease number;

g. as appropriate, the Unit Agreement name, number, and Participating Area name; and

h. as appropriate, the Communitization Agreement

5. Environmental Obligations and Disposition of Production (43 CFR 3162.5-1, 3162.7-1 and 40 CFR 302.4)

a. With BLM approval, water produced from newly completed wells may be temporarily disposed of into unlined pits for up to 90 days. During this initial period, application for the permanent disposal method shall be made to this office in accordance with Onshore Order No. 7 (BLM 1993). If underground injection is proposed, a USEPA or state permit shall also be obtained.

b. Spills, accidents, fires, injuries, blowouts, and other undesirable events must be reported to this office within the timeframes in NTL-3A (BLM 1979b).

c. Gas may be vented or flared during emergencies, well evaluation, or initial production tests for a time period of up to 30 days or the production of 50 million cubic feet (mmcf) of gas, whichever occurs first. After this period, approval from this office shall be obtained to flare or vent gas in accordance with NTL-4A (BLM 1980b).

6. Well Identification (43 CFR 3162.6)

Each drilling, producing, or abandoned well shall be identified with the operator's name, the lease serial number, the well number, and the surveyed description of the well (either footages or the quarter-quarter section, the section, township, and range). All markings shall be legible and in a conspicuous place.

7. Site Security (43 CFR 3162.7.5)

a. Oil storage facilities shall be clearly identified with a sign, and tanks must be individually identified (43 CFR 3162.6 (c)).

b. Site security plans shall be completed within 60 days of production startup (43 CFR 3162.7-5(c)).

c. Site facility diagrams shall be filed in this office within 60 days after facilities are installed or modified (43 CFR 3162.7-5(d)(1)).

8. Confidentiality (43 CFR 3162.8)

All submitted information not marked "CONFIDENTIAL INFORMATION" will be available for public inspection upon request.

D.9 Production and Development

D.9.1 Production

Production begins when a well yields oil or gas in commercial quantities. If formation pressure is sufficient to raise oil to the surface, the well is completed as a flowing well. A pumping unit is installed if the formation pressure is not sufficient to bring the oil to the surface. When the well is completed as a free-flowing well, an assembly of valves and special connections known as a "Christmas tree" (so called because of its many branch like fittings) is installed on top of the casing to regulate the flow of the well. Later, when the natural pressure declines, the Christmas tree can give way to a simple wellhead arrangement of valves and a pumping unit to lift the oil artificially. Many pumping units are "beam" style pumps that are powered by electric motors or gasoline engines. Most gas wells produce by natural flow and do not require pumping. Surface facilities at a flowing well are usually in a small area containing a gas well Christmas tree, a dehydrator, a produced water pit, and a meter house. Separators, condensate tanks, and compressors may be included. Some gas wells require continuous water pumping as water entering the well chokes off the gas flow.

D.9.2 Development

New field development may be analyzed under NEPA by means of an environmental assessment (EA) or environmental impact statement (EIS) usually after the second or third confirmation well is drilled. The operator should then have an idea of the extent of drilling and disturbance required to extract and produce the oil and gas. When an oil or gas discovery is made, a well spacing pattern must be established before development drilling begins. Development can take years and include from one or two wells to more than a hundred wells per field. However, the reasonably foreseeable development scenario for this planning document should only forecasts two additional wells per field. Roads to producing wells are upgraded to all-weather roads as necessary. Pipelines, electrical transmission lines, separators, dehydrators, sump pits, and compressor stations soon follow. Sometimes oil and gas processing facilities are built in or adjacent to the field.

D.9.2.1 Further Seismic Testing

More detailed seismic work can be done to achieve better definition of the petroleum reservoir. Diagonal seismic lines can be required to tie the previous seismic work to the discovery well. The discovery well can be used to conduct studies to correct the previous seismic work and provide more accurate subsurface data.

D.9.2.2 Spacing Requirements

A well spacing pattern must be established before development drilling begins. Information considered in establishment of a spacing pattern includes data from the discovery well on porosity, permeability, pressure, composition, and depth of formations in the reservoir; well production rates and type (predominantly oil or gas); and the economic effect of the proposed spacing on recovery. The state of Montana establishes well spacing patterns for both exploratory and development wells which the BLM generally adopts. The state specifies the minimum distance from lease lines or government survey lines for the bottom-hole location of the well bore depending upon depth of the well. The spacing regulations determine the acres assigned to each well. Spacing unit size is established to provide for the most efficient and economic recovery of oil or gas from a reservoir. Normal well spacing ranges from 40 acres to 640 acres (refer to Billings/Pompeys Pillar RFD for Oil and Gas). Wells deeper than 11,000 feet can be no closer than 1,650 feet to other producing wells below 11,000 feet. Only one producing well per formation is allowed in each 40, 80, 160, 320, and 640-acre unit.

D.9.2.3 Drilling of Development Wells

The procedures used in drilling development wells are the same as those used for wildcat wells, but usually with less subsurface sampling, testing, and evaluation. The rate at which development wells are drilled in a field depends on factors such as whether the field is developed on a lease basis or unitized basis, the probability of profitable production, the availability of drilling equipment, lease requirements, and the degree to which limits of the field are known. Some fields go through several development phases, the first resulting from the original discovery and others from later discovery. A field can be considered fully developed and produce for several years, and then a well may be drilled to a deeper or shallower pay zone. Discovery of a new pay zone in an existing field is a "pool" discovery (as distinguished from a new field discovery). A pool discovery may lead to the drilling of additional wells, often from the same drilling pad as existing wells.

D.9.2.4 Inspections

Geophysical operations and lease operations are inspected to determine compliance with approved permits, to resolve conflicts or correct problems and to determine effectiveness and need of lease stipulations. All inspections are documented. Operators are required to correct problems or violations.

D.9.2.5 Surface Requirements

Field development activities that cause surface disturbance include access roads, well sites, production facility sites, flow line and utility line routes and waste disposal sites. Surface uses in a gas field will be less than in an oil field, because gas wells are usually drilled on larger spacing units. The spacing pattern of 640 acres per well, which is common in gas fields, will require only one well per section and might require only ½ mile of access roads and pipelines. Production facilities include separation and storage equipment. Separation equipment is required when production includes a combination of oil, gas, or water and storage equipment is required for holding liquids prior to sales.

D.9.2.6 Flow Lines

Oil and gas are transferred from the well to storage facilities through small diameter (<6 inches) flow lines. Flow lines can be on the surface, buried or elevated Produced water, gas, or polymerized liquid is transferred from storage facilities to injection wells for secondary recovery.

D.9.2.7 Separating, Treating, and Storage

Any water or gas associated with produced oil is separated from the oil before it is placed in storage tanks. The treating facilities are located at a storage tank battery. Low-pressure petroleum that must be pumped from the well is treated in a single separation. High pressure, flowing petroleum can require several stages or separation, with a pressure reduction accompanying each stage.

Produced gas is sold when there is sufficient volume, necessary transportation, a market, and it is economical. Generally, if the volume of produced gas is too low for sales, it is used as fuel for well pump engines and heating fuel for the treaters. If the volume of produced gas exceeds fuel requirements on the lease but gas sales are not possible, the gas can be flared or vented into the atmosphere when authorized by permit in accordance with state and federal regulations. When water is produced with the hydrocarbons, it is separated before the gas is removed. In primary operations, where natural pressures or gravity causes the petroleum in the reservoir to flow to the wellbores, the degree of mixing is high enough to require chemical and heat treatment to separate the oil and water. In secondary production, where water injection or other methods are used to force additional petroleum to the wellbore, the oil and water often are not highly emulsified. In this case, the oil and water can be separated by gravity in a tall settling tank. Produced water can be disposed of by injection into the subsurface, surface evaporation or beneficial purposes such as water for livestock or irrigation.

Produced water from oil and gas operations is normally disposed of by subsurface injection or in surface pits. Regardless of the method of disposal, it must be acceptable to the BLM, in accordance with the requirements of Onshore Oil and Gas Order No. 7, titled “Disposal of Produced Water.” Disposal of produced water by injection wells requires permits from the Montana Board of Oil and Gas Conservation. When produced water is disposed underground, it is introduced or injected under pressure into a subsurface horizon containing water of equal or poorer quality. Produced water may be injected into the producing zone from which it originated to stimulate oil production. Dry holes or depleted wells are commonly converted for saltwater disposal and occasionally new wells are drilled for this purpose. The law and regulations require that all injection wells be permitted under the Underground Injection Control program.

Under the Underground Injection Control approval process, the disposal well must be pressure tested to ensure the integrity of the casing. The disposal zone must also be isolated by use of tubing and mechanical plug called a packer. The packer seals off the inside of the casing and only allows the injected water to enter the disposal zone. The tubing and packer are also pressure tested to ensure their integrity. These pressure tests confirm isolation of the disposal zone from possible usable water zones. The oil is transported to storage tanks through flow lines after separation from any water or gas. Storage tanks are usually located on the lease either at the producing well or at a central production facility. The number and size of tanks are dependent upon the type and amount of production on the lease.

D.9.3 Abandonment

When drilling wells are unsuccessful or production wells are no longer useful, the well is plugged, equipment is removed from the well site or production facility site, and the site is abandoned. The well bore is secured by placing cement plugs to isolate hydrocarbon-producing formations from contaminating other mineral or water bearing formations. The site and roads are then restored as near as possible to original contours. Topsoil is replaced and the recontoured areas are seeded. Reclamation of access roads and well sites on privately owned surface is completed according to the surface owner’s requirements.

Rehabilitation requirements generally are made a part of the Application for Permit to Drill. Upon completion of abandonment and rehabilitation operations, the lessee or operator notifies the Miles City DO that the location is ready for inspection. Final abandonment will not be approved until the required surface reclamation work has been completed to the satisfaction of the BLM or surface owner. The period of bond liability for the well site is terminated after approval of final abandonment. Reclamation of the reserve pit is part of the well site reclamation process. Reserve pit reclamation includes removal of fluids to a disposal well or commercial pit and burial of solids in the pit. Solids should not be buried until dry and then covered with a minimum of 6 feet of native soil. Any pit liner may be buried in place. Methods such as solidification or dewatering may be used to help dry the solids.

D.10 Regulations, Laws, and Special Procedures

D.10.1 Unit and Communitization Agreements

Unit and communitization agreements can be formed in the interest of conservation and to allow for the orderly development of oil and gas reserves. A unit agreement provides for the recovery of oil and gas from the lands as a single consolidated entity without regard to separate lease ownerships. An exploratory unit is used for the discovery and development of the field in an orderly and efficient manner. Paying and nonpaying well determinations are made for each well drilled. If the well is nonpaying as defined by the agreement, the production is allocated on a lease basis. If the well is a paying unit well, a participating area is formed and the production is allocated to all interest owners in the participating area based on surface area. A secondary unit is formed after the field has been defined and enhanced recovery techniques are being utilized. Secondary recovery techniques include water injection, natural gas injection, or carbon dioxide injection. Injection is initiated to maintain the reservoir pressure to maintain oil production. The agreement provides for the allocation of production among all the interest owners.

A communitization agreement combines two or more leases (federal, state, or fee) that otherwise could not be independently developed in conformity with established well spacing patterns. The leases within the spacing unit share in the costs and benefits of the well drilled in the spacing unit. Therefore, unit and communitization agreements can lessen the amount of damage to the environment and save dollars by eliminating unnecessary wells, roads, pipelines, and lease equipment.

D.10.2 Split Estate

Part of the area included in the planning area contains lands known as split estate lands. These are lands where the surface ownership is different from the mineral ownership. Management of federal oil and gas resources on these lands is somewhat different from management on lands where both surface and mineral ownership is federal. On split estate lands where the surface ownership is private, the BLM places necessary restrictions and requirements on its leases and permit approvals and works in cooperation with the surface owner. BLM has established policies for the management of federal oil and gas resources in accordance with federal laws and regulations.

The BLM does not have the legal authority to regulate how private surface is managed. BLM does have the statutory authority to require measures by lessees to avoid or minimize adverse impacts that may result from federally authorized mineral lease activities. These measures, in the form of lease stipulations or permit conditions of approval, are intended to protect or preserve the privately owned resources and prevent adverse impacts to adjoining lands, not to dictate management to the surface owner. The term split estate can also refer to lands where the surface ownership is federal and the mineral ownership is private. In this situation, BLM is the surface owner, and works in cooperation with the proponent and the state regulatory agency that approves private mineral applications. BLM has responsibilities in this situation under the previously mentioned statutes; however, BLM does not have the authority to approve or disapprove the mineral owner's actions. The mineral estate owner usually has the right to enter the land and use the surface that is necessary and reasonable for mineral development through either a reserved or an outstanding right contained in the deed.

D.11 Summary – Billings/Pompeys Pillar Reasonably Foreseeable Development Scenario

D.11.1 Summary

The Billings Resource Management Plan will guide management for the approximately 434,158 acres of federally managed surface and about 690,000 subsurface (oil and gas mineral estate) acres administered by the Billings Field Office (BiFO) in western Big Horn, Carbon, Golden Valley, Musselshell, Stillwater, Sweet Grass, Wheatland and Yellowstone counties. Conventional oil and natural gas occurrence and development potential ranges from Low to Moderate across the entire field office area. The occurrence potential for coal bed natural gas (CBNG), and gas from organic shales ranges from Low to High. Development potential for CBNG ranges from Low to Moderate; development potential for gas from organic shales ranges from Low to Moderate.

The BLM administers approximately 690,000 acres of federal minerals (for fluid minerals) within the Billings Field Office. The RFD forecasts the following level of development in the entire Billings FO planning area.

The expected Billings FO total wells drilled per year equals 20 per year with three to four federal wells per year over a 20-year span. These wells could be in one of the three areas identified in the table below. The RFD scenario classified moderate potential lands as having the potential for one to five wells drilled per township per year. Low potential lands have the potential for less than one well per year per township.

Table 15. RFD Projected Forecast Drilling Depths, and Forecast Surface Disturbance by Basin

Location	Common Drilling Depth in Feet	Likely Product	Size of Drill Site in Acres	Access and Ancillary Facilities in Acres
Central Montana Uplift and Bull Mountain Basin	5,000	Oil with associated gas; CBNG	2	1.5
Big Horn Basin	7,000	Oil with associated gas; Gas; CBNG	3	1.5
Crazy Mountain Basin	8,000 – 10,000	Gas	4	1.5

The RFD scenario identified these areas and contains more information about them. Total annual disturbance for federal wells is approximately 13.5 acres to 27 acres of short-term disturbance (several years) and 5.5 to 15.5 acres of long-term disturbance for federal wells drilled in the Billings FO.

A complete copy of the Billings RMP RFD can be found at http://www.blm.gov/mt/st/en/fo/billings_field_office/rmp/docs.html. This information is presented only as a summary.

D.11.2 Background

The Billings Field Office is located in south-central Montana. There has been a long history of exploration and development within this area. The following information describes the historic activities associated with drilling in the area, with subsequent information, charts and graphs indicating the cumulative number of wells drilled, and notable dates.

D.11.2.1 Drilling and Development History

The first drilling in Montana occurred near the 'Cruse' oil seeps, in Carbon County, in about 1890. Drilling occurred along strike (northwest-southeast) to the Beartooth Mountain front. Only small volumes of low gravity oil were reportedly produced.

The Elk Basin area in Carbon County experienced early development, as an extension of the Wyoming portion of the field. The first drilling occurred about 1915; this activity pre-dated the Mineral Leasing Act of 1920. At that time, oil was developed as a placer mineral on mining claims located under the General Mining Act of 1872, as amended by the Petroleum Placers Act of 1897. Many of these petroleum placers went to patent (became private land).

Further drilling occurred as operators attempted to expand the known producing area along the axis of the Elk Basin anticline. The field limits were extended to the northwest, with the later discoveries at Elk Basin Northwest, Clarks Fork, the Clarks Fork North and Clarks Fork South fields. In the same time frame (1910s-1920s), exploration occurred at the Dry Creek Dome in central Carbon County. Natural gas was discovered there in 1919, and extended into Golden Dome in 1962.

In Big Horn County, the Soap Creek Oil Field was discovered in 1920, and expanded by new drilling as recent as 2005. The Hardin Gas Field was discovered in 1928, and expanded by new drilling into the 1930s, with the most recent well drilled in 1975.

Early prospecting for oil was concentrated around geologic structures that were exposed at the surface. These structures, often called "Sheepherder Anticlines", were believed to be indicators of potential oil reservoirs within subsurface structures. Most of the early exploration and development occurred in proximity to these exposed anticlines and domes. Many oil and gas fields are still identified by these surface structures (i.e., Golden Dome, Gage Dome, and Dean Dome). Often, the earliest wells drilled within these structures were not drilled deep enough, and did not achieve a discovery.

Many other anticlines were 'breached' by erosion that exposed the reservoir rock, leaving only stained or bleached rock as indications of the past presence of oil. This is the case on the east flank of Red Dome, in Carbon County. Here, the Triassic Chugwater Formation red beds have zones of sandstones that are gray; the oil, while it was in the rock, prevented the oxidation of the iron in the rock matrix and cement.

The first drilling in Musselshell County was not successful, but by 1920, oil was discovered in the Heath Lime, at Devil's Basin field. By the end of 1921, oil had been discovered in the Soap Creek field in Big Horn County and the Lake Basin field in Stillwater County. Mosser Dome field in southwestern Yellowstone County opened in 1936.

In the 1940s, additional oil fields were discovered in Musselshell County, including Gage Dome, Ragged Point, Big Wall and Melstone. All were surface structures ('Sheepherder Anticlines'), with the oil found in Mississippian carbonate rocks (Amsden, Kibbey, Heath and Tyler Formations). New fields were discovered in surface structures (Ivanhoe, Stensvad, Delphia, Hawk Creek, Hiawatha, Keg Coulee, Pole Creek, Mason Lake), and existing fields were expanded, into the 1960s. Similarly, exploration of the surface structure at Wolf Springs resulted in a oil discovery in Yellowstone County in 1955 and at Weed Creek in 1967.

The first gas production in Sweet Grass County occurred when the Six Shooter Dome field was discovered in 1947. First production in Golden Valley County occurred with the discovery of gas in the Big Coulee field, in 1948. Later that year, oil was discovered in Golden Valley's Woman's Pocket and Devil's Pocket fields.

In 1953, the Ash Creek field in southern Big Horn County was discovered, with oil produced from the Upper Cretaceous Shannon Formation. The Mackay Dome and Roscoe Dome fields, in southern Stillwater and Carbon Counties, respectively, were discovered in the late 1950s. Both produce from Lower Cretaceous sandstones.

In the 1970s, the Rapelje gas field in Stillwater County was discovered.

Two oil price shocks in the 1970s resulted in a quadrupling of the price of oil over a four-year period, from around $3.00 per barrel in mid-1973, to over $12.00 per barrel in 1977. The Islamic Revolution in Iran in 1979 sent oil prices still higher, with the price peaking at over $38.00 per barrel in 1981.

The rapid increase in the price of oil resulted in a rush of new prospect generation. Even prospects that had a low probability of finding product were drilled. Conservation and new discoveries led to in an increased supply while demand was falling, resulting in a price collapse, with oil in Montana falling below $10.00 per barrel in early 1986. For the rest of the 1980s, the BLM allowed operators to leave their wells 'shut in' (in a non-producing status). This policy allowed operators to maintain their wells without having to operate them at an economic loss.

In 1992, the BLM terminated the above policy, and issued new regulations that provided for a reduced royalty rate for oil properties that averaged less than 15 barrels of oil per well per day (so-called 'stripper wells/properties). The royalty rate reduction (RRR) was intended to reduce operators' operating costs, and encourage the greatest ultimate recovery of oil. The BLM anticipated that operators would take advantage of this incentive and work over existing wells to restore or increase production within these properties. The RRR would be recalculated every year, and could fall further if the average production rate continued to decrease. The regulation was in effect for about 14 years, and terminated effective February 1, 2006 (when the oil price exceeded the threshold established in the regulation).

D.11.2.2 Federal Surface and Mineral Ownership within the Billings Field Office

Charts 1 and 2, below, provide the distribution of surface and mineral ownership, by county, within the Billings Field Office. Chart 3 presents surface and mineral ownership by Federal Agency. The data are from LR 2000, as of May 20, 2009.

Chart 1: Surface, Oil & Gas Mineral Ownership, and acres of O&G leases by County (All Surface Management Agencies)

County	Federal Surface Ownership	Federal Oil & Gas Mineral Ownership	O&G Leases	Leased Acres[2]	Percent of O&G Leased
Big Horn[1]	0.00	3,989.29	5	3,934.47	98.6%
Carbon	552,535.16	609,950.40	99	53,575.45	8.7%
Golden Valley	31,644.63	66,550.80	17	18,062.96	27.1%
Musselshell	100,458.12	140,922.31	79	56,641.02	40.2%
Stillwater	192,196.58	243,221.64	32	24,232.23	10.0%
Sweet Grass	297,308.04	356,378.33	25	19,772.71	5.5%
Wheatland	63,604.24	84,463.43	3	1,022.52	1.2%
Yellowstone	69,725.38	105,708.45	20	9,023.20	8.5%
Totals	**1,307,472.15**	**1,611,184.65**	**280**	**186,264.56**	**11.5%**

Footnotes:
1. Big Horn County includes only the portion within the Billings Field Office (west of R. 39 E.)
2. Including leases sold at the Montana Competitive Oil and Gas Lease Sale held on January 27, 2009

Chart 2: Surface, Oil & Gas Mineral Ownership and acres of O&G leases by County, Managed by the Billings Field Office

County	BLM-Managed Surface	BLM-Managed Oil & Gas Mineral Ownership	O&G Leases	Leased Acres[2]	Percent of O&G Leased
Big Horn[1]	0.00	3,989.29	5	3,934.47	98.6%
Carbon	205,156.46	260,531.10	97	51,228.80	19.7%
Golden Valley	7,844.19	42,750.36	17	18,062.96	42.3%
Musselshell[3]	92,632.23	129,108.14	793	56,401.02	43.7%
Stillwater	5,519.49	55,944.07	29	19,994.23	35.7%
Sweet Grass	15,833.58	73,584.22	25	19,772.71	26.8%
Wheatland	1,194.91	22,054.10	3	1,022.52	4.6%
Yellowstone	69,725.38	105,708.45	20	9,023.20	8.5%
Totals	**397,906.24**	**689,680.44**	**275**	**179,439.91**	**26.0%**

Footnotes
1. Big Horn County includes only the portion within the Billings Field Office (west of R. 39 E.)
2. Including leases sold at the Montana Competitive Oil and Gas Lease Sale held on January 27, 2009;
3. There are two Federal O&G leases that include both BLM and FWS surface

Chart 3: Total Surface and Oil and Gas Mineral Ownership (in acres) by County, by Surface Management Agency

	BLM		FS		FWS		BIA		NPS	
County	Surface	Oil & Gas Mineral Ownership	Surface	Oil & Gas Mineral Ownership	Surface	Oil & Gas Mineral Ownership	Surface	Oil & Gas Mineral Ownership	Surface	Oil & Gas Mineral Ownership
Big Horn[1]	0	0	0	0	0	0	0	3,989.29		
Carbon	205,156.46	260,531.10	323,682.62	323,683.22					23,696.08	25,736.08
Golden Valley	7,844.19	42,750.36	23,800.44	23,800.44						
Musselshell	92,632.23	129,108.14	0	0	7,825.89	11,814.17				
Stillwater	5,519.49	55,944.07	185,604.65	185,885.13						
Sweet Grass	15,833.58	73,584.22	281,474.46	282,794.11	1,072.44	1,392.44				
Wheatland	1,194.91	22,054.10	62,409.33	62,409.33						
Yellowstone	69,725.38	105,708.45	0	0						
Totals	**397,906.24**	**689,680.44**	**876,971.50**	**878,572.23**	**8,898.33**	**13,206.61**	**0**	**3,989.29**	**23,696.08**	**25,736.08**

Footnotes
1. Big Horn County includes only the portion within the Billings Field Office (west of R. 39 E.).